BUREAU OF LAND MANAGEMENT
Nevada State Office

Appendix F

Hydraulic Fracturing White Paper

This White Paper on hydraulic fracturing is derived from the Hydraulic Fracturing White Paper (BLM 2013) written and developed by the Bureau of Land Management, Wyoming State Office. It has been modified to meet the criteria for the State of Nevada.

I. BACKGROUND

Hydraulic fracturing (HF) is a well stimulation process used to maximize the extraction of underground resources – oil, natural gas and geothermal energy. The HF process includes the acquisition of water, mixing of chemicals, production zone fracturing, and HF flowback disposal.

In the United States, HF has been used since the 1940's. Early on, the HF process utilized pressures that are of a much smaller magnitude than those used today.

The HF process involves the injection of a fracturing fluid and propping agent into the hydrocarbon bearing formation under sufficient pressure to further open existing fractures and/or create new fractures. This allows the hydrocarbons to more readily flow into the wellbore. HF has gained interest recently as hydrocarbons previously trapped in low permeability or "tight" sand and shale formations are now technically and economically recoverable. As a result, oil and gas production has increased significantly in the United States.

Prior to the development of HF in hydrocarbon bearing tight gas and shale formations, domestic production of conventional resources had been declining. In response to this decline, the federal government in the 1970's through 1992, passed tax credits to encourage the development of unconventional resources. It was during this time that the HF process was further advanced to include the high-pressure multi-stage HF operations being conducted today.

Generally, HF can be described as follows:

1. Water, proppant, and chemical additives are pumped at extremely high pressures down the wellbore.

2. The fracturing fluid is pumped through perforated sections of the wellbore and into the surrounding formation, creating fractures in the rock. The proppant holds the fractures open during well production.

3. Company personnel continuously monitor and gauge pressures, fluids and proppants, studying how the sand reacts when it hits the bottom of the wellbore, slowly increasing the density of sand to water as HF progresses.

4. This process may be repeated multiple times, in “stages” to reach maximum areas of the formation(s). The wellbore is temporarily plugged between each stage to maintain the highest fluid pressure possible and get maximum fracturing results in the rock.

5. The plugs are drilled or removed from the wellbore and the well is tested for results.

6. The pressure is reduced and the fracturing fluids are returned up the wellbore for disposal or treatment and re-use, leaving the sand in place to prop open the fractures and allow the oil/gas to flow.

II. OPERATIONAL ISSUES

Wells that undergo HF may be drilled vertically, horizontally, or directionally and the resultant fractures induced by HF can be vertical, horizontal, or both. Wells in Nevada (NV) may extend to depths greater than 10,000 feet or less than 1,000 feet, and horizontal sections of a well may extend several thousand feet from the production pad on the surface. Prior to initiating HF, a cement bond log and pressure test is required and evaluated to ensure the integrity of the cement and its bond to both the well casing and the geologic formation.

The total volume of fracturing fluids is generally 95-99% water. The amount of water needed to fracture a well in NV depends on the geologic basin, the formation, and depth and type of well (vertical, horizontal, directional), and the proposed completion process.

In general, approximately 50,000 to 300,000 gallons may be used to fracture shallow vertical wells in NV, while approximately 800,000 to 10 million gallons may be used to fracture deep tight sand gas horizontal or directionally drilled wells in NV.

Proppant, consisting of synthetic or natural silica sand, may be used in quantities of a few hundred tons for a vertical well to a few thousand tons for a horizontal well.

Drilling muds, drilling fluids, water, proppant, and HF fluids are stored in onsite tanks or lined pits during the drilling and/or completion process. Equipment transport and setup can take several days, and the actual HF and flowback process can occur in a few days up to a few weeks. For oil wells, the flowback fluid from the HF operations is treated in an oil-water separator before it is stored in a lined pit or tank located on the surface. Where gas wells are flowed back using a “green completion process” fluids are run through a multi-phase separator, which are then piped directly to enclosed tanks or to a production unit. Nevada currently does not have large volumes of gas production, but this may change depending on the formation.

Gas emissions associated with the HF process are captured when the operator utilizes a green completion process. Where a green completion process is not utilized, gas associated with the well may be vented and/or flared until "saleable quality" product is obtained in accordance with federal and state rules and regulations. The total volume of emissions from the equipment used (trucks, engines) will vary based on the pressures needed to fracture the well, and the number of zones to be fractured.

Under either completion process, wastewaters from HF may be disposed in several ways. For example, the flowback fluids may be stored in tanks pending reuse; the resultant waste may be re-injected using a permitted injection well, or the waste may be hauled to a licensed facility for treatment, disposal and/or reuse.

Disposal of the waste stream following establishment of "sale-quality" product, would be handled in accordance with Onshore Order #7 regulations and other state/federal rules and regulations.

Fracturing Fluids

As indicated above, the fluid used in the HF process is approximately 95to 99 percent water and a small percentage of special-purpose chemical additives and proppant. There is a broad array of chemicals that can be used as additives in a fracture treatment including, but not limited to, hydrochloric acid, anti-bacterial agents, corrosion inhibitors, gelling agents (polymers), surfactants, and scale inhibitors. The 1 to 5 percent of chemical additives translates to a minimum of 5,000 gallons of chemicals for every 1.5 million gallons of water used to fracture a well (Paschke, Dr. Suzanne. USGS, Denver, Colorado. September 2011). Water used in the HF process is generally acquired from surface water or groundwater in the local area. Information on obtaining water and water rights is discussed below.

The Nevada Division of Minerals (NDOM) has regulations that require the reporting of the amount and type of chemicals used in a HF operation in "FracFocus" within 60 days of HF completion for public disclosure. For more information concerning FracFocus and HF, refer to the FracFocus website at www.fracfocus.org and the NDOM website at minerals.state.nv.us.

Re-Fracturing

Re-fracturing of wells (RHF) may be performed after a period of time to restore declining production rates. RHF success can be attributed to enlarging and reorienting existing fractures while restoring conductivity due to proppant degradation and fines plugging. Prior to RHF, the wellbore may be cleaned out. Cleaning out the wellbore may recover over 50% of the initial proppant sand. Once cleaned, the process of RHF is the same as the initial HF. The need for RHF cannot be predicted.

Water Availability and Consumption Estimates

According to the Nevada State Water Plan (March 1999), total statewide water withdrawals for NV are forecasted to increase about 9 percent from 4,041,000 acre-feet in 1995 to 4,391,000 acre-feet in 2020, assuming current levels of conservation. Approximately one-half of these withdrawals are consumptively used. This projected increase in water use is directly attributable to Nevada's increasing population and related increases in economic endeavors.

The anticipated rise in total statewide water withdrawals primarily reflects expected increases in public supply for M&I water usage to meet the needs of a growing urban population, with expanding commercial and industrial activities. Nevada's population is projected to reach about 3,047,000 by the year 2020, with about 95 percent of these residents served by public water systems (NDWP, March 1999).

M&I withdrawals currently account for about 13 percent of the water used in NV. Annual M&I water use is projected to increase from 525,000 af in 1995 to 1,034,000 af in 2020 (24 percent of total water withdrawals) based upon existing water use patterns and conservation measures. About 77 percent of water withdrawals are for agricultural use. Approximately 6 to 7 percent of statewide water withdrawals occur in the mining industry (NDWP, March 1999).

Interest in obtaining the necessary water supplies for wildlife and environmental needs is increasing. Additionally, the popularity of water-based outdoor recreation continues to grow. It is anticipated that these trends will continue, resulting in increased water supply demands for wildlife, environmental and recreational purposes.

Currently, surface water supplies are virtually fully appropriated. The increase in total statewide demand, particularly M&I water use, is expected to be met via better demand management (conservation), use of alternative sources (reused water, reclaimed water and greywater), purchases, leases or other transfers from existing water users, and by new groundwater appropriations. Much of the state's unappropriated groundwater is located in basins at a distance from urban centers. Thus, increasing attention will be placed on interbasin and intercounty transfers, and implementation of underutilized water management tools such as water marketing and water banking. Water for instream flow purposes, wildlife protection, environmental purposes and recreation will likely be generated by increased conservation and the acquisition of existing water rights (NDWP, March 1999).

Potential Sources of Water for Hydraulic Fracturing

Freshwater-quality water is required to drill the surface-casing section of the wellbore per Federal regulations; other sections of the wellbore (intermediate and/or production strings) would be drilled with appropriate quality makeup water as necessary. This is done to protect usable water zones from contamination, to prevent mixing of zones containing different water quality/use classifications, and to minimize total freshwater volumes. With detailed geologic well logging during drilling operations, geologists/mud loggers on location identify the bottoms of these usable water zones, which aids in the proper setting of casing depths.

Several sources of water are available for drilling and/or HF in NV. Because Nevada's water rights system is based in the prior appropriation doctrine, water cannot be diverted from a stream/reservoir or pumped out of the ground for drilling and/or HF without reconciling that diversion with the prior appropriation doctrine. Like any other water user, companies that drill or hydraulically fracture oil and gas wells must adhere to NV water laws when obtaining and using specific sources of water.

Below is a discussion of the sources of water that could potentially be used for HF. The decision to use any specific source is dependent on BLM authorization at the APD stage and the ability to satisfy the water appropriation doctrine. From an operators' standpoint, the decision regarding which water source will be used is primarily driven by the economics associated with procuring a specific water source.

Water transported from outside the state. The operator may transport water from outside the state. As long as the transport and use of the water carries no legal obligation to NV, this is an allowable source of water from a water rights perspective.

Irrigation water leased or purchased from a landowner. The landowner may have rights to surface water, delivered by a ditch or canal that is used to irrigate land. The operator may choose to enter into an agreement with the landowner to purchase or lease a portion of that water. This is allowable, however, in nearly every case; the use of an irrigation water right is likely limited to irrigation uses and cannot be used for well drilling and HF operations. To allow its use for drilling and HF, the owner of the water right and the operator must apply to change the water right through a formal process.

Treated water or raw water leased or purchased from a water provider. The operator may choose to enter into an agreement with a water provider to purchase or lease water from the water provider's system. Municipalities and other water providers may have a surplus of water in their system before it is treated (raw water) or after treatment that can be used for drilling and HF operations. Such an arrangement would be allowed only if the operator's use were compliant with the water provider's water rights.

Water treated at a waste water treatment plant leased or purchased from a water provider. The operator may choose to enter into an agreement with a water provider to purchase or lease water that has been used by the public, and then treated as wastewater. Municipalities and other water providers discharge their treated waste water into the streams where it becomes part of the public resource, ready to be appropriated once again in the priority system. But for many municipalities a portion of the water that is discharged has the character of being "reusable." As a result, it is possible that after having been discharged to the stream, it could be diverted by the operator to be used for drilling and HF operations. Such an arrangement would only be appropriate with the approval of the Nevada Department of Environmental Protection, State Engineer's Office (NDEP) and would be allowed only if the water provider's water rights include uses for drilling and HF operations.

New diversion of surface water flowing in streams and rivers. New diversion of surface waters in most parts of the state are rare because the surface streams are already "over appropriated," that is, the flows do not reliably occur in such a magnitude that all of the vested water rights on those streams can be satisfied. Therefore, the only time that an operator may be able to divert water directly from a river is during periods of high flow and less demand. These periods do occur but not reliably or predictably.

Produced Water. The operator may choose to use water produced in conjunction with oil or gas production at an existing oil or gas well. The water that is produced from an oil or gas well is under the administrative purview of the NDEP, Underground Injection Control Program (UIC) and is either non-tributary, in which case, it is administered independent of the prior appropriation doctrine; or is tributary, in which case, the depletions from its withdrawal must be fully augmented if the depletions occur in an over-appropriated basin. The result in either case is that the produced water is available for consumption for other purposes, not just oil and gas operations. The water must not be encumbered by other needs and the operator must obtain a proper well permit from the NDEP before the water can be used for drilling and HF operations.

Reused or Recycled Drilling Water. Water that is used for drilling of one well may be recovered and reused in the construction of subsequent wells. The BLM encourages reuse and recycling of both the water used in well drilling and the water produced in conjunction with oil or gas production. However, as described above, the operator must obtain the right to use the water for this purpose.

On-Location Water Supply Wells. Operators may apply for, and receive, permission from the NDEP to drill and use a new water supply well. These wells are usually drilled on location to provide an on-demand supply. These industrial-type water supply wells are typically drilled deeper than nearby domestic and/or stock wells to minimize drawdown interference, and have large capacity pumps. The proper construction, operation and maintenance, backflow prevention and security of these water supply wells are critical considerations at the time they are proposed to minimize impacts to the well and/or the waters in the well and are under the jurisdiction of the NDEP. Plugging these wells is under the jurisdiction of the NDEP and BLM.

III. Potential Impacts to Usable Water Zones

Impacts to freshwater supplies can originate from point sources, such as chemical spills, chemical storage tanks (aboveground and underground), industrial sites, landfills, household septic tanks, and mining activities. Impacts to usable waters may also occur through a variety of oil and gas operational sources which may include, but are not limited to, pipeline and well casing failure, and well (gas, oil and/or water) drilling and construction of related facilities. Similarly, improper construction and management of open fluids pits and production facilities could degrade ground water quality through leakage and leaching.

Should hydrocarbons or associated chemicals for oil and gas development, including HF, exceeding US Environmental Protection Agency (EPA)/NDEP standards for minimum concentration levels migrate into potable water supply wells, springs, or usable water systems, it could result in these water sources becoming non-potable. Water wells developed for oil and gas drilling could also result in a draw down in the quantity of water in nearby residential areas depending upon the geology; however it is not currently possible to predict whether or not such water wells would be developed.

Usable groundwater aquifers are most susceptible to pollution where the aquifer is shallow (within 100 feet of the surface depending on surface geology) or perched, are very permeable, or connected directly to a surface water system, such as through floodplains and/or alluvial valleys or where operations occur in geologic zones which are highly fractured and/or lack a sealing formation between the production zone and the usable water zones. If an impact to usable waters were to occur, a greater number of people could be affected in densely populated areas versus sparsely populated areas characteristic of NV.

Potential impacts on usable groundwater resources from fluid mineral extraction activities can result from the five following scenarios:

1. Contamination of aquifers through the introduction of drilling and/or completion fluids through spills or drilling problems such as lost circulation zones.
2. Communication of the induced hydraulic fractures with existing fractures potentially allows for HF fluid migration into usable water zones/supplies. The potential for this impact is likely dependent on the local hydraulic gradients where those fluids are dissolved in the water column.

3. Cross-contamination of aquifers/formations may result when fluids from a deeper aquifer/formation migrate into a shallower aquifer/formation due to improperly cemented well casings.

4. Localized depletion of perched aquifer or drawdown of unconfined groundwater aquifer.

5. Progressive contamination of deep confined, shallow confined, and unconfined aquifers if the deep confined aquifers are not completely cased off, and geologically isolated, from deeper oil bearing units. An example of this would be salt water intrusion resulting from sustained drawdown associated with the pumping of groundwater.

The impacts above could occur as a result of the following processes:

Improper casing and cementing.
A well casing design that is not set at the proper depths or a cementing program that does not properly isolate necessary formations could allow oil, gas or HF fluids to contaminate other aquifers/formations.

Natural fractures, faults, and abandoned wells.
If HF of oil and gas wells result in new fractures connecting with established natural fractures, faults, or improperly plugged dry or abandoned wells, a pathway for gas or contaminants to migrate underground may be created posing a risk to water quality. The potential for this impact is currently unknown but it is generally accepted that the potential decreases with increasing distance between the production zone and usable water zones. This potential again is dependent upon the site specific conditions at the well location.

Fracture growth.
A number of studies and publications report that the risk of induced fractures extending out of the target formation into an aquifer—allowing hydrocarbons or other fluids to contaminate the aquifer —may depend, in part, on the formation thickness separating the targeted fractured formation and the aquifer. For example, according to a 2012 Bipartisan Policy Center report, the fracturing process itself is unlikely to directly affect freshwater aquifers because fracturing typically takes place at a depth of 6,000 to 10,000 feet, while drinking water aquifers are typically less than 1,000 feet deep. Fractures created during HF have not been shown to span the distance between the targeted oil formation and freshwater bearing zones. If a parcel is sold and development is proposed in usable water zones, those operations would have to comply with federal and/or state water quality standards or receive a Class II designation from the NDEP.

Fracture growth and the potential for upward fluid migration, through volcanic, sedimentary and other geologic formations depend on site-specific factors such as the following:

1. Physical properties, types, thicknesses, and depths of the targeted formation as well as those of the overlying geologic formations.

2. Presence of existing natural fracture systems and their orientation in the target formation and surrounding formations.

3. Amount and distribution of stress (i.e., in-situ stress), and the stress contrasts between the targeted formation and the surrounding formations.

Hydraulic fracture stimulation designs include the volume of fracturing fluid injected into the formation as well as the fluid injection rate and fluid viscosity; this information would be evaluated against the above site specific considerations.

Fluid leak and recovery (flowback) of HF fluids.
Not all fracturing fluids injected into the formation during the HF process may be recovered at the surface. Fluid movement into smaller fractures or other geologic substructures can be to a point where flowback efforts will not recover all the fluid or that the pressure reduction caused by pumping during subsequent production operations may not be sufficient to recover all the fluid that has leaked into the formation. It is noted that the fluid loss due to leakage into small fractures and pores is minimized by the use of cross-linked gels.

Willberg et al. (1998) analyzed HF flowback and described the effect of pumping rates on cleanup efficiency in initially dry, very low permeability (0.001 millidarcy) shale. Some wells in this study were pumped at low flowback rates (less than 3 barrels per minute (bbl/min). Other wells were pumped more aggressively at greater than 3 bbl/min. Thirty-one percent of the injected HF fluids were recovered when low flowback rates were applied over a 5-day period. Forty-six percent of the fluids were recovered when aggressive flowback rates were applied in other wells over a 2-day period. In both cases, additional fluid recovery (10 percent to 13 percent) was achieved during the subsequent gas production phase, resulting in a total recovery rate of 41 percent to 59 percent of the initial volume of injected HF fluid. Ultimate recovery rate however, is dependent on the permeability of the rocks, fracture configuration, and the surface area of the fracture(s).

The ability of HF chemicals to migrate in an undissolved or dissolved phase into a usable water zone is likely dependent upon the location of the sealing formation (if any), the geology of the sealing formation, hydraulic gradients and production pressures.

HF fluids can remain in the subsurface unrecovered, due to “leak off” into connected fractures and the pores of rocks. Fracturing fluids injected into the primary hydraulically induced fracture can intersect and flow (leak off) into preexisting smaller natural fractures. Some of the fluids lost in this way may occur very close to the well bore after traveling minimal distances in the hydraulically induced fracture before being diverted into other fractures and pores. Once “mixed” with the native water, local and regional vertical and horizontal gradients may influence where and if these fluids will come in contact with usable water zones, assuming that there is inadequate recovery either through the initial flowback or over the productive life of the well. Faults, folds, joints, etc., could also alter localized flow patterns as discussed below.

The following processes can influence effective recovery of the fracture fluids:

Check-Valve Effect

A check-valve effect occurs when natural and/or newly created fractures open and HF fluid is forced into the fractures when fracturing pressures are high, but the fluids are subsequently prevented from flowing back toward the wellbore as the fractures close when the fracturing pressure is decreased (Warpinski et al., 1988; Palmer et al., 1991a).

A long fracture can be pinched-off at some distance from the wellbore. This reduces the effective fracture length. HF fluids trapped beyond the “pinch point” are unlikely to be recovered during flowback and oil/gas is unlikely to be recovered during production.

In most cases, when the fracturing pressure is reduced, the fracture closes in response to natural subsurface compressive stresses. Because the primary purpose of HF is to increase the effective permeability of the target formation and connect new or widened fractures to the wellbore, a closed fracture is of little use. Therefore, a component of HF is to “prop” the fracture open, so that the enhanced permeability from the pressure-induced fracturing persists even after fracturing pressure is terminated. To this end, operators use a system of fluids and “proppants” to create and preserve a high-permeability fracture-channel from the wellbore deep into the formation.

The check-valve effect takes place in locations beyond the zone where proppants have been placed (or in smaller secondary fractures that have not received any proppant). It is possible that some volume of stimulation fluid cannot be recovered due to its movement into zones that were not completely “propped” open.

Adsorption and Chemical Reactions

Adsorption and chemical reactions can also prevent HF fluids from being recovered. Adsorption is the process by which fluid constituents adhere to a solid surface and are thereby unavailable to flow with groundwater. Adsorption to coal is likely; however, adsorption to other geologic material (e.g., shale, sandstone) is likely to be minimal. Another possible reaction affecting the recovery of fracturing fluid constituents is the neutralization of acids (in the fracturing fluids) by carbonates in the subsurface.

Movement of Fluids outside the Capture Zone

Fracturing fluids injected into the target zone flow into fractures under very high pressure. The hydraulic gradients driving fluid flow away from the wellbore during injection are much greater than the hydraulic gradients pulling fluid flow back toward the wellbore during flowback and production (pumping) of the well. Some portion of the fracturing fluids could be forced along the hydraulically induced fracture to a point beyond the capture zone of the production well. The size of the capture zone will be affected by the regional groundwater gradients, and by the drawdown caused by producing the well. Site-specific geologic, hydrogeologic, injection pressure, and production pumping details should provide the information needed to estimate the dimension of the production well capture zone and the extent to which the fracturing fluids might disperse and dilute.

Incomplete Mixing of Fracturing Fluids with Water

Steidl (1993) documented the occurrence of a gelling agent that did not dissolve completely and actually formed clumps at 15 times the injected concentration in an induced fracture. Steidl also directly observed gel hanging in stringy clumps in many other induced fractures. As Willberg et al. (1997) noted, laboratory studies indicate that fingered flow of water past residual gel may impede fluid recovery. Therefore, some fracturing fluid gels appear not to flow with groundwater during production pumping and remain in the subsurface unrecovered. Such gels are unlikely to flow with groundwater during production, but may present a source of gel constituents to flowing groundwater during and after production.

Authorization of any future proposed projects would require full compliance with local, state, and federal regulations and laws that relate to surface and groundwater protection and would be subject to routine inspections by the BLM and the State of Nevada Commission on Mineral Resources, Division of Minerals Memorandum of Understanding dated January 9, 2006, prior to approval.

IV. Geologic Hazards (including seismic/landslides)

Nevada is the 3rd most tectonically active state in the union. Since the 1850s there have been 63 earthquakes with a magnitude greater than 5.5, the cutoff for a destructive earthquake. Potential geologic hazards caused by HF include induced seismic activity in addition to the tectonic activity already occurring in the state. Induced seismic activity could indirectly cause a surficial landslide where soils/slopes are susceptible to failure. Landslides involve the mass movement of earth materials down slopes and can include debris flows, soil creep, and slumping of large blocks of material. Any destructive earthquake also has the potential to induce liquefaction in saturated soils.

Earthquakes occur when energy is released due to blocks of the earth's crust moving along areas of weakness or faults. Earthquakes attributable to human activities are called "induced seismic events" or "induced earthquakes." In the past several years induced seismic events related to energy development projects have drawn heightened public attention. Although only a very small fraction of injection and extraction activities at hundreds of thousands of energy development sites in the United States have induced seismicity at levels that are noticeable to the public, seismic events caused by or likely related to energy development have been measured and felt in Alabama, Arkansas, California, Colorado, Illinois, Louisiana, Mississippi, Nebraska, Nevada, New Mexico, Ohio, Oklahoma, and Texas.

A study conducted by the National Academy of Sciences (Induced Seismicity Potential in Energy Technologies, National Academy of Sciences, 2012) studied the issue of induced seismic activity from energy development. As a result of the study, they found that:

1. The process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events; and

2. Injection for disposal of waste water derived from energy technologies into the subsurface does pose some risk for induced seismicity, but very few events have been documented over the past several decades relative to the large number of disposal wells in operation.

The potential for induced seismicity cannot be made at the leasing stage; as such, it will be evaluated at the APD stage should the parcel be sold/issued, and a development proposal submitted.

V. Spill Response and Reporting

Spill Prevention, Control, and Countermeasure (SPCC) Plans – EPA's rules include requirements for oil spill prevention, preparedness, and response to prevent oil discharges to navigable waters and adjoining shorelines. The rule requires that operators of specific facilities prepare, amend, and implement SPCC Plans. The SPCC rule is part of the Oil Pollution Prevention regulation, which also includes the Facility Response Plan (FRP) rule. Originally published in 1973 under the authority of §311 of the Clean Water Act, the Oil Pollution Prevention regulation sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires the operator of these facilities to develop and implement SPCC Plans and establishes procedures, methods, and equipment requirements (Subparts A, B, and C). In 1990, the Oil Pollution Act amended the Clean Water Act to require some oil storage facilities to prepare FRPs. On July 1, 1994, EPA finalized the revisions that direct facility owners or operators to prepare and submit plans for responding to a worst-case discharge of oil.

In addition to EPA's requirements, operators must provide a plan for managing waste materials, and for the safe containment of hazardous materials, per Onshore Order #1 with their APD proposal. All spills and/or undesirable events are managed in accordance with Notice to Lessee (NTL) 3-A for responding to all spills and/or undesirable events related to HF operations.

Certain oil and gas exploration and production wastes occurring at or near wellheads are exempt from the Clean Water Act, such as: drilling fluids, produced water, drill cuttings, well completion, and treatment and stimulations fluids. In general, the exempt status of exploration and production waste depends on how the material was used or generated as waste, not necessarily whether the material is hazardous or toxic.

VI. Public Health and Safety

The intensity, and likelihood, of potential impacts to public health and safety, and to the quality of usable water aquifers is directly related to proximity of the proposed action to domestic and/or community water supplies (wells, reservoirs, lakes, rivers, etc.) and/or agricultural developments. The potential impacts are also dependent on the extent of the production well's capture zone and well integrity. Nevada's Standard Lease Stipulations and Lease Notices specify that oil and gas development is generally restricted within 500 feet of riparian habitats and wetlands, perennial water sources (rivers, springs, water wells, etc.) and/or floodplains. Intensity of impact is likely dependent on the density of development.

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